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Techno-Economic Assessment and Optimisation of Self-Sufficient Biomethane Systems for Regional Decarbonisation

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ABSTRACT

Existing gas network infrastructure are important national energy assets, transporting mostly fossil-derived natural gas to end-users. Biomethane, methane derived from anaerobic digestion (AD) of organic matter, presents a potential route to replace fossil fuels with home-grown renewable gas. Combined with carbon capture and storage (CCS) of the CO_2 in the biogas potentially results in carbon negative energy. This work seeks to understand the feasibility of operating a part of the gas network isolated from the main natural gas network fully on biomethane in Scotland. We present an integrated techno-economic optimisation framework for designing self-sufficient biomethane islands, applied to the Inverness network. The model, implemented as a nonlinear program (NLP), maximises annual net profit from biomethane sales and Green Gas Support Scheme (GGSS) tariffs subject to practical constraints such as GGSS-compliance of ≥50 % waste-derived biomethane, seasonal supply, land/scale, demand balancing with centralised liquefied natural gas (LNG) storage, and a life-cycle global warming potential (GWP) metric. Three archetypes are analysed: Type A (crop-dominated, manure co-digestion), Type B (food/industrial wastes, grass/manure support), and Type C (distillery residues + grass/manure). In Inverness, feasible solutions include: Type A (2 large ~92, 000 m^3 digestion plants at ~23 ha/site producing 97.39 $Mm^3\,y^{-1}$ of gas; net revenue £13.4 M y^{-1}; GWP ~42.2 $ktCO_2e/y$), Type B (1 ~97, 000 m^3 plant at ~24 ha, producing 48.69 $Mm^3\,y^{-1}$ gas; net revenue £9.4 m y^{-1}; GWP ~48.0 $ktCO_2e/y$), and Type C (2 large ~110, 000 m^3 plants at ~27 ha, producing 97.4 $Mm^3\,y^{-1}$ of gas; net revenue £13.0 m y^{-1}; GWP ~47.2 $ktCO_2e/y$). Type B is most profitable per unit capacity due to gate-fee feedstocks but carries higher GWP (mostly from grass-silage cultivation). The model balances a combination of dynamic feeding of different recipes with using a centralised LNG storage to buffers seasonal deficits and maximise asset utilisation; optional CO_2 liquefaction (~87.7 kt y^{-1} per large site at ~151 kWh t^{-1}) enables near/net-negative operation under low-carbon power. Our results find that the business model is feasible for Inverness and highlight the value of systems thinking and the need for policy reform (particularly lifting the 250 GWh y^{-1} cap for GGSS and rewarding carbon intensity rather than just waste-derived methane) to unlock larger, efficient, low-emission regional systems.

Keywords: Alternative Fuels, Modelling and Simulations, Biofuels, Renewable and Sustainable Energy, Technoeconomic Analysis

INTRODUCTION

Anaerobic digestion (AD) has become an increasingly important technology in the transition to low-carbon and circular energy systems, owing to its capacity to stabilise organic wastes, recover renewable biomethane, and reduce greenhouse-gas emissions from agriculture and food supply chains. The broader environmental and policy context for this transition is underscored by national targets for Net Zero, 2050 for the UK and 2045 for Scotland, which position renewable gas as a critical enabler of decarbonisation across heat, transport, and industrial applications. The UK Biomass Strategy targets 30-40 TWh of biomethane by 2050, up from 6-8TWh [1], with the National Energy System Operator (NESO) suggesting 64 TWh by 2050[2]. The national gas infrastructure is an important national energy asset that risks decommissioning should fossil fuel natural gas decline as electrification of heating and transport dominate. Within these contexts, we seek to assess the feasibility, both technically and economically, of operating regional gas networks entirely on locally produced biomethane, integrating waste management, renewable energy conversion, and seasonal storage into a unified system design.

From a modelling perspective, AD has traditionally been described using mechanistic kinetic models, including simplified first-order approaches and more detailed models such as the ADM1. First-order kinetics remain widely applied in strategic decision-support settings due to their tractability and ability to capture degradation dynamics across co-digestion systems [3], but still need to assure control of methane yield, inhibition, and stability, for co-digestion by considering C/N ratios, solids loading, retention time and synergy effects. In our previous work [4], we developed a mixed-integer linear programming scheduling model to optimise feed scheduling for a single AD plant to optimise both electricity and biomethane gas-to-grid for maximising profit, considering co-digestion recipes, dynamic pricing, and gas storage. The model used a co-digestion model for understanding the gas yields from blending different feedstocks from [3] Additional literature indicates growing interest in hybrid frameworks that combine mechanistic understanding with optimisation and control, including the incorporation of price forecasting, nonlinear programming (NLP), and model predictive control (MPC) to manage temperature, substrate scheduling, and economic performance in AD systems [5].

At system level, optimisation frameworks have increasingly integrated logistics, crop availability, plant sizing, price signals, and life cycle assessments (LCA) [6], [7]. Despite this progress, relatively few studies integrate logistics, co-digestion modelling, economic optimisation, environmental performance, and policy constraints within a single modelling framework [8]. This gap is particularly relevant when systems must meet regulatory requirements such as the Green Gas Support Scheme (GGSS), which mandates that at least 50 % of biomethane be derived from eligible waste sources. This constraint strongly influences feedstock blending, reactor sizing, and plant economics due to the subsidy scheme. In practical deployment, additional challenges arise from seasonal demand variability, land availability, feedstock availability and transport distances, and the need for flexible gas-balancing infrastructure such as centralised bio-LNG storage, all of which directly affect the feasibility of establishing a self-sufficient regional gas system.

To address these challenges, working with gas networks and industrial partners, this work develops a unified NLP optimisation framework that integrates feedstock logistics, co-digestion performance, methane-release dynamics, LNG storage requirements, and life-cycle greenhouse gas emissions into a coherent decision-support tool to optimise the design and economics of AD sites that could realistically deliver flexible green gas to a part of the gas network. The framework is applied to the Inverness region as a detailed case study considering real feedstock availabilities and potential site locations, enabling the systematic evaluation of multiple plant archetypes under shared technical, economic, and policy constraints. The resulting analysis offers insight into the techno-economic viability of regional biomethane systems, the role of seasonal storage [9], and the implications of current UK policy structures for large-scale renewable-gas deployment.

METHODS

We formulate an NLP in Pyomo [10] solved with IPOPT [11]. The model couples: (i) feedstock logistics with seasonality and a 50-mile catchment from identified potential site locations; (ii) co-digestion performance via first-order decay over solids retention time (SRT) and empirical blending correlations (C:N, biodegradability); (iii) demand balancing with potential for centralised bio-LNG storage on the network; (iv) GGSS constraints (≥50 % waste share; tiering of tariffs based on gas amounts); and (v) GWP covering cultivation, transport and parasitic energy. A scale-factor adjusts digestion volume/land for lower-energy wastes and GGSS compliance; excessive scaling is penalised in the objective.

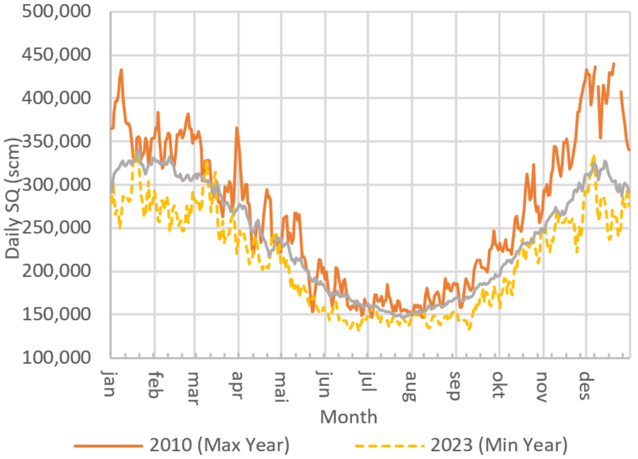

Figure 1. Inverness daily demand profiles (min/avg/max; 2010 as conservative 1-in-20 winter). Values are derived from the historic Scotland LDZ dataset.

Mathematical Formulation

The NLP combines economic, operational, and policy-driven constraints to optimise the site design and feeding patterns to meet regional gas demands at maximum profit. The mathematical model is discretised in time for weekly demand for strategic scenario analysis and sufficiently detailed to capture the dynamic methane-release behaviour, seasonal balancing requirements, and regulatory conditions (particularly the ≥50 % waste-derived biomethane threshold specified by the GGSS).

The optimisation seeks to maximise the annual net profit of the biomethane island. Revenue is derived from biomethane sales to the gas grid and, where applicable, GGSS tariff payments; costs include feedstock procurement, transport logistics, annualised capital expenditure, operational expenditures, and scale-related penalties applied when plant size significantly exceeds benchmark industrial references. This leads to the following general objective:

$$\max_{\mathbf{x}} \Pi = \left(P_{\text{gas}} Q_{\text{bm}} + T_{\text{GGSS}} Q_{\text{bm}}^{\text{elig}}\right) - \left(C_{\text{feed}} + C_{\text{OPEX}} + C_{\text{CAPEX}}^{\text{ann}} + C_{\text{transport}} + \phi_{\text{scale}}\right) \tag{1}$$

where Q_{bm} represents total biomethane production, $Q_{\text{bm}}^{\text{elig}}$ is the portion eligible for GGSS support, and ϕ_{scale} is the nonlinear scaling penalty used to discourage unrealistic reactor upscaling beyond benchmark industrial AD site references.

A defining feature of the system is compliance with the GGSS requirement that at least 50 % of the biomethane energy content must originate from eligible wastes. Because each feedstock carries a distinct methane-yield potential, this constraint is expressed on an energy basis, ensuring that compliance cannot be met merely by mass-based blending:

$$\frac{\sum_{i \in \mathcal{W}} E_i Q_i}{\sum_{i \in \mathcal{F}} E_i Q_i} \geq 0.50 \tag{2}$$

where E_i denotes the methane energy yield per tonne of substrate i, Q_i its annual quantity, and $\mathcal{W}$ is the set of GGSS-eligible waste feedstocks from all feeds $\mathcal{F}$. This constraint is highly influential in determining plant scale, especially for crop-dominated (Type A) systems, and is responsible for driving the 35–62 % volume-expansion factors observed across Inverness scenarios.

To represent the time-dependent degradation behaviour of substrates, the model incorporates first-order kinetic decay, a widely used simplification in strategic AD planning [3]. This allows gas production to be traced over the effective SRT, enabling weekly matching between production and district gas demand:

$$M_{i,t} = \sum_{\tau=0}^{t} Q_{i,\tau}\, Y_i \left(1 - e^{-k_i (t-\tau)}\right), t \in \{1, \dots, 52\} \tag{3}$$

where $M_{i,t}$ is methane released at week t from substrate i, Y_i is its specific methane yield, and k_i a first-order rate constant. This reflects the dynamic gas-release effects, which are particularly important when high-moisture residues such as pot ale dominated blends.

The Inverness network exhibits pronounced winter peaks, requiring that surplus summer biomethane be liquefied and stored as bio-LNG for later reinjection. The required LNG capacity is defined as the maximum cumulative surplus over the annual horizon:

$$V_{\text{LNG}}^{\text{req}} = \max_{t \in [1,365]} \left(\sum_{\tau=1}^{t} Q_{\text{bm},\tau} - D_\tau\right) \cdot \rho_{\text{LNG}} \tag{4}$$

where D_t is district demand and ρ_{LNG} the gas-to-LNG volumetric conversion factor. This constraint is central to identifying feasible island-mode operation, ensuring that biomethane production and storage remain sufficient to meet peak-demand shortfalls.

CASE STUDY

The case study in this work is a real gas network in Inverness, Scotland, with data obtained from our industrial partners. We use historical regional gas demands to define the demand profiles (see Figure 1), with the 2010 demand profile used as a conservative 1-in-20 winter standard to ensure the system is designed for robustness. We use an existing industrial site as a large-scale reference, with a 57 MW class site (~500 GWh y^{-1} historically with a footprint of ~17 ha). For "real demand-scale" testing, the GGSS 250 GWh cap is relaxed while maintaining the ≥50 % waste rule; tiering is applied to eligible volumes. Available feedstocks are obtained from an existing national feedstock database from industrial partners, with their characteristics and availabilities shown in Table 1. GWP figures for crops are derived from [12]. GWP numbers provided in the results aggregates cultivation (dominant for grass silage), transport (feeds + digestate), and site parasitic load (CHP electricity, auxiliary use). CH_4 leakage is set to 0 % in the base cases but has been noted at ~3–4 % in empirical studies.

Plant Archetypes

Three representative plant archetypes were defined to capture the main categories of feedstocks available within the 50-mile Inverness sourcing radius, obtained from industrial partners and to reflect typical UK AD deployment models. These archetypes differ in substrate composition, yield characteristics, infrastructure requirements, and their ease of compliance with the GGSS ≥50 % waste-derived biomethane rule.

Energy-Crop-Dominated Systems (Type A): These plants are based primarily on energy crops (wholecrop and cereal silages), co-digested with grass silage and cattle manure to ensure stable nutrient profiles. Energy crops provide relatively high and predictable methane yields, supporting flexible scheduling to match seasonal demand. However, because cultivated crops are not GGSS-eligible wastes, Type A systems must incorporate

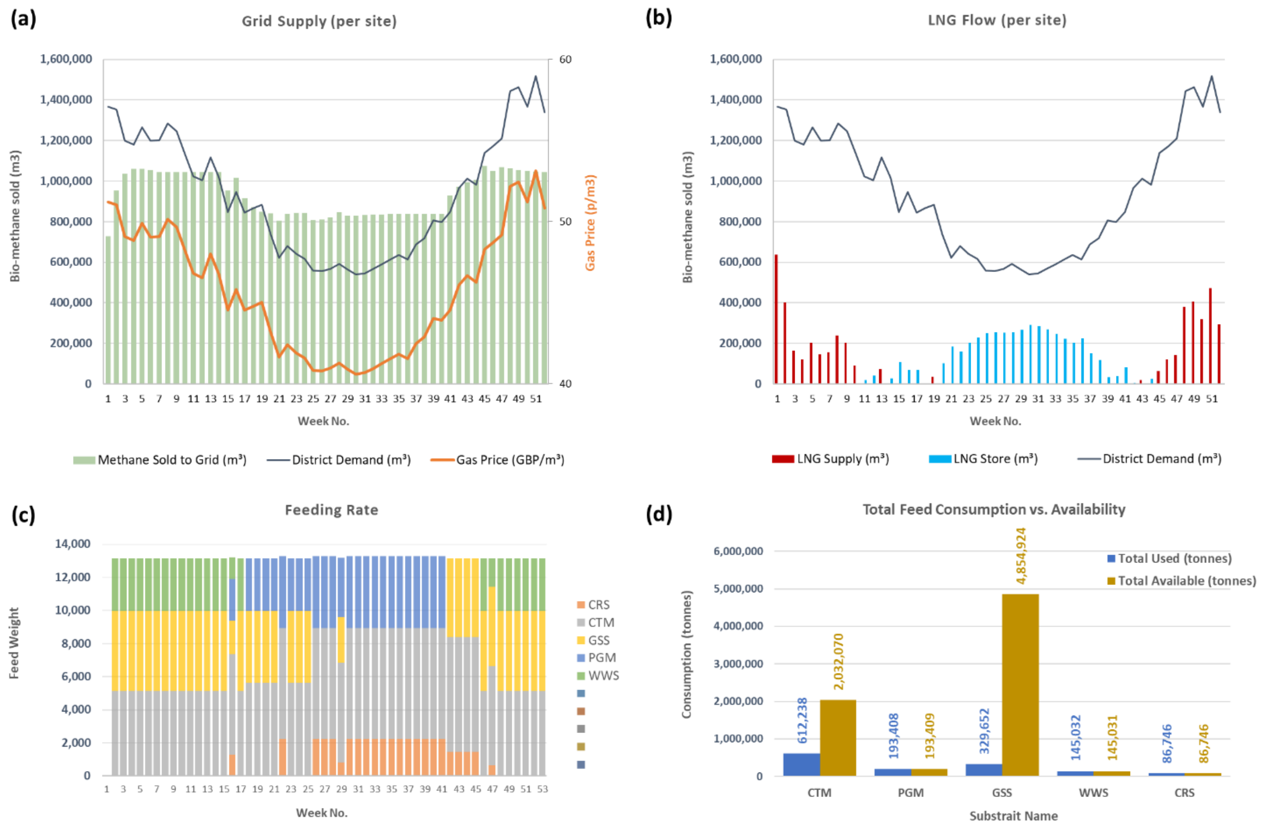

Figure 2. Operational performance – Type A plant (Inverness): (a) production vs demand; (b) LNG schedule; (c) blend ratios; (d) feed availability/use.

substantial manure volumes to meet the ≥50 % waste threshold, which drives the required 35 % scale increase (digester volume factor 1.35 in comparison to our reference industrial sites) observed in the Inverness configuration.

Food- and Industrial-Waste-Based Systems (Type B): These utilise household food waste (HFW) and industrial food waste (IFW), both of which count entirely toward the GGSS waste fraction. These substrates typically have low or negative net cost due to gate fees, enabling strong economic performance. However, their compositional variability necessitates co-digestion with grass silage and manure to maintain buffering capacity and prevent acidification. Feedstock availability limits Inverness to a single large-scale Type B plant, requiring 43 % larger digesters above benchmarks.

Distillery-Residue-Based Systems (Type C): These configurations are built around distillery by-products, particularly draff and pot ale, both abundant and fully waste-classified within the Inverness region. These substrates offer favourable co-digestion synergies with grass silage and manure, but raw pot ale's low solids content significantly reduces energy density. Consequently, Type C requires the largest scale increase of 62 % above the benchmark digester sizing, leading to higher digestion volumes and land requirements compared with Types A and B.

RESULTS

Type A: Crop-Dominated Configuration

The crop-based Type A scenario makes extensive use of energy crops (wholecrop and cereal silages), grass silage, and regionally abundant cattle manures. The optimisation determines that two large-scale AD plants constitute the maximum feasible configuration for Inverness under this scenario, with each site requiring a 35 % scale increase above the benchmark to comply GGSS requirements. This results in a digestion volume of approximately 92, 000 m^3 per plant, with an associated land footprint of roughly 23 ha per site. The resulting biomethane output reaches 97.39 million m^3 $year^{-1}$, of which 48.69 million m^3 $year^{-1}$ is derived from waste feedstocks, meeting the GGSS threshold exactly. Table 2 summarises the techno-economic performance of the sites with annual sales of £86.2 million, feedstock costs of £38.9 million, annualised CAPEX of £19.1 million, and OPEX of £14.9 million yielding a net annual revenue of £13.4 million across the two-plant configuration to meet demands.

Figure 2a (Inverness Type A performance) shows

Table 1: Feedstocks for Type-A and Type-B plants in the selected area. Note EBMP is experimental biomethane potential and TBMP is theoretical biomethane potential. k is the rate constant, C/N is carbon to nitrogen ratio and GWP is the global warming potential associated with growing 1 tonne of the feedstock. Type-C feedstocks not shown to save space as these were not shown to be a part of the optimal configurations.

Substrate	**Abbr.**	**Available weight**	**Cost**	**Total Solids**	**Volatile Solids**	**EBMP**	**TBMP**	**C/N**	**k**	**GWP**
		Tonnes	£/t	kg_{TS} / t_{feed}	kg_{VS} / t_{TS}	m^3CH_4 / t_{VS}	m^3CH_4 / t_{VS}	-	$week^{-1}$	-
Cattle Manure	CTM	2,032,070	15	250	800	230	380	20	0.7	0
Pig Manure	PGM	193,409	10	250	800	250	410	14	1	0
Grass Silage	GSS	4,854,924	35	350	900	370	440	25	0.9	0.39
Wholecrop Wheat Silage	WWS	145,031	70	350	870	390	450	32	1	0.31
Cereal Straw	CRS	86,746	70	850	850	220	380	75	0.4	0
Household Food Wast	HFW	77,703	15	240	920	500	600	15	1.8	0
Industrial Food Waste	IFW	42,000	20	240	920	600	650	20	1.5	0

that production tracks seasonal demand through deliberate modulation of feedstock blends. Higher-yield crops are favoured during winter months, whereas lower-energy materials dominate during periods of suppressed demand. This allows the plants to maximise the digester volume usage and still hit the GGSS requirements across the year, while surpluses are still generated to maximise profit and still hit overall gas demands via gas storage. This flexible scheduling produces a yearly surplus of approximately 4.8 million m^3 $plant^{-1}$, which is redirected to the centralised LNG facility. The associated GWP for Type A totals ~42, 200 tCO_2e $year^{-1}$, driven predominantly by grass-silage cultivation (33, 400 tCO_2e) and transport impacts (8, 800 tCO_2e).

Type B: HFW and IFW Configuration

Type B shifts the focus to HFW and IFW, supported by grass silage and manure to maintain process stability. Due to limited volumes of food waste within the Inverness catchment, the optimisation identifies only one feasible large-scale site, which would need to be partnered with a Type A site to deliver the full region's gas demand. This plant requires a 43 % volume expansion over the industrial benchmark sizing, resulting in a total digestion volume of approximately 97, 000 m^3 and a land area of 24 ha.

Annual biomethane production in this configuration is 48.69 million m^3, with half (24.35 million m^3) derived from eligible waste streams. Despite being only half the scale of the Type A two-plant scenario, Type B shows strong economic performance, benefiting from the gate-fee revenues associated with food waste. As shown in Table 3, annual sales revenue reaches £43 million, with feedstock procurement costing only £16.2 million, significantly lower than in Type A. When combined with annualised CAPEX (£9.8 million) and OPEX (£7.6 million), this yields a net annual revenue of £9.4 million for a single facility.

Unlike Type A, the food-waste-dominated system exhibits less flexibility in modulating feedstock blends, resulting in a greater reliance on LNG storage to buffer seasonal mismatches. The Type B plant generates a larger relative surplus, approximately 6.4 million m^3 $year^{-1}$, equivalent to 13 % of total production. However, Type B also carries the highest GWP among the scenarios (48, 000 tCO_2e $year^{-1}$), again dominated by emissions from grass-silage cultivation (~38, 700 tCO_2e) and transportation (9, 300 tCO_2e).

Type C: Distillery Residue Configuration

The Type C scenario evaluates draff and pot-ale feedstocks from local distillery operations, supplemented by grass silage and manure. Feedstock availability supports the deployment of two large-scale plants, but low methane-potential substrates (particularly raw pot-ale) necessitate the largest scale expansion of the three scenarios: a 62 % increase (scale factor 1.62), giving a digestion volume of approximately 110, 000 m^3 per plant and a land requirement of 27 ha per site.

Combined annual biomethane production is 97.4 million m^3, with 48.7 million m^3 from eligible wastes. Total sales revenue reaches £85.8 million, with feedstock costs (£36 million), annualised CAPEX (£21 million), and OPEX (£16 million) resulting in a net revenue of £13 million $year^{-1}$, broadly comparable to Type A. Production under this scenario remains relatively stable throughout the year due to the low degree of flexibility offered by distillery residues. The system accordingly generates a larger annual surplus of ~7.2 million m^3 (15 %), which must be stored as LNG to satisfy winter deficits.

Table 2: Optimisation results- Estimated performance and economic metrics for Type-A 57MW AD plants in Inverness

Number of benchmark sites required	MW	2 x 57
Max. feasible number of sites	MW	2 x 57
Total estimated land required	ha	2 x 23
Performance/Economic Metric	**Unit**	**Total Sites Value**
Total biomethane Produced	m^3/yr	97,385,400
Waste-derived Volume	m^3/yr	48,692,700
Waste-derived Share	%	50%
Total Sell	£m/yr	86.2
Total Feed Cost	£m/yr	38.9
Total CapEx	£m	202.4
Total OpEx	£m/yr	14.9
Annualised CapEx	£m/yr	19.1
Net Revenue	£m/yr	13.4
Volume Scale Factor	-	1.35
Total Digestion Vol. per plant	m^3	92,000

Table 3: Performance, cost, and LNG implications of the selected plant configuration for Inverness biomethane island

Selected configuration		(1xA) + (1xB)
Total land required	ha	(23 ha) + (24 ha)
Total annual costs	£m/yr	69.9
Total net revenue	£m/yr	16.1
Total GWP	tCO_2e	90,200
Total LNG storage	m^3LNG	18,500
Cent. LNG facility total capital	£m	67
Cent. LNG facility Opex	£m	2.0

The Type C configuration exhibits a total GWP of approximately 47, 200 tCO_2e year^{-1}, with the majority (78 %) attributable to grass-silage cultivation and the remainder to logistics. Notably, the exclusion of pot-ale syrup, a higher-solids, higher-methane-potential variant, suggests that future scenarios including concentrated distillery co-products could significantly reduce both plant size and GWP.

Optional CO_2 liquefaction (per large site)

For each large-scale Inverness AD facility, the biogenic CO_2 stream from upgrading can be processed via an optional on-site liquefaction unit. Our model estimates an annual CO_2 flow of ~87, 700 t CO_2 year^{-1} per site, requiring ~£61 million in capital expenditure and ~£0.71 million year^{-1} in O&M costs, with electricity demand of 151 kWh t^{-1} CO_2. These energy requirements are treated as a parasitic load on the CHP system rather than external grid purchases, ensuring consistency with the broader techno-economic system boundary. Although optional, CO_2 liquefaction has the potential to shift AD systems toward near- or net-negative emissions, particularly when the captured CO_2 can be diverted for sequestration or utilised in local industrial markets.

The feasibility of implementing CO_2 liquefaction, however, depends heavily on future policy incentives and the evolution of CO_2 commodity pricing. The current GGSS framework does not reward CO_2 capture, meaning the investment must presently be justified solely on environmental grounds, as current UK CO_2 market prices do not provide a profitable investment case [13]. Shifting policy from a strict ≥50 % waste-content rule toward a carbon-intensity-based support mechanism would materially improve the economic case for CO_2 capture and valorisation. As emerging low-carbon markets develop, particularly in Scotland's food, beverage, and synthetic-fuel sectors, liquefied CO_2 could represent a meaningful future revenue stream, strengthening the long-term viability of regional biomethane systems.

DISCUSSION

The optimisation results for Inverness reveal that system feasibility depends on the interplay between feedstock availability, GGSS constraints, and seasonal balancing needs. The most profitable solution identified in the report is a hybrid configuration comprising one Type A and one Type B plant based on feedstock availability. This combination leverages the high methane yield and operational stability of crop-supported co-digestion (Type A) together with the strong economic performance of food-waste-based digestion (Type B), achieving £16.1 million year^{-1} in net revenue and requiring 18, 500 m^3 of centralised LNG storage to meet winter peak demand. The details of the optimal system is given in Table 3.

This hybrid arrangement also moderates the limitations of the individual systems. By combining the two plant types, the system achieves a more favourable balance of economic efficiency and environmental performance, while reducing sensitivity to feedstock variability. Seasonal surplus remains critical across all scenarios, necessitating dedicated centralised LNG infrastructure.

CONCLUSION

This work applied a unified techno-economic optimisation framework to assess the feasibility of an Inverness biomethane island. We showed that it is feasible in this region to meet all current gas demands within current policy and feedstock availability restrictions with a novel arrangements of technologies and feeding patterns, while still providing an attractive business case. Future work should examine hybrid designs that combine the economic strengths of Type B with the lower emissions and operational flexibility of crop- or distillery-based systems, as well as the potential of higher-value co-products such as pot-ale syrup to reduce required plant scale. Policy implications are significant: the 250 GWh y^{-1} GGSS cap and binary ≥50 % waste rule limit optimal system design that do not encourage flexible operation. Shifting toward carbon-intensity-based incentives, alongside support for CO_2 capture, would better align economic and environmental outcomes and accelerate deployment.

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